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Demand Response from Day-Ahead Hourly Pricing for Large Customers

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I. Introduction

In recent years, policymakers have shown increasing interest in dynamic pricing as a means to encourage demand response (DR). Proponents of real-time pricing (RTP) and critical peak pricing (CPP) rates rely heavily on conceptual portrayals of the DR benefits that would inure from their wide-scale adoption.[1] A few empirical studies of voluntary RTP tariffs implemented by vertically integrated utilities confirm that at least some of the largest customers can adjust their usage in response to high prices.[2] Recent CPP and RTP pilot programs involving residential customers suggest that some of these customers too might adjust usage to price signals.[3] However, the overall experience with RTP in vertically integrated settings has been less than encouraging, with several notable exceptions.[4] Furthermore, these results do not necessarily translate to situations in which RTP is implemented as the default service in the context of retail competition.

During the past five years, regulatory commissions in several states (Maryland, New Jersey, New York, and Pennsylvania) have adopted default-service pricing for large customers that is indexed to day-ahead or real-time energy markets operated by Independent System Operators (ISOs). These initiatives were driven primarily by retail market development goals with DR being a secondary objective in a few cases.[5] While there are indications default service RTP has resulted in more customers facing, and possibly responding to, high prices, no study has been undertaken to fully characterize or measure this response.[6]

Despite its promise, critical questions must be resolved before policymakers will be comfortable implementing dynamic pricing on a large scale. To what extent does default-service RTP actually encourage price response? Does RTP-type default service also satisfy the goal of switching customers to competitive suppliers? To what extent do retail market choices, such as hedges, complicate RTP's capacity to elicit price response? What are the relative roles of default-service RTP and ISO-sponsored emergency programs in eliciting DR? Which factors and characteristics account for differences in customers' willingness and ability to respond to hourly varying prices?

We contribute to the resolution of these issues, for *day-ahead* RTP, with a study of the largest customers at Niagara Mohawk, a National Grid Company (NMPC), that have been exposed to default-service electricity pricing indexed to the New York Independent System Operator (NYISO) day-ahead market since retail competition was introduced in 1998.[7]

The study, conducted in two phases, included customer surveys and interviews (in summer 2003 and fall 2004) to collect information on customers' facility and business characteristics, their perceived ability and willingness to respond to prices or other signals to curtail, and their electricity supply and hedging choices.[8] These data were combined with NMPC billing records to estimate price response. The study focused on the summers of 2000-2004, to characterize how customers adapted to changing market circumstances, alternative supply choices, and, after 2001, opportunities to participate in NYISO demand response programs.

The 149 subject customers, served under the "SC-3A" service classification, range in peak demand from 2 MW (the threshold for inclusion) to over 20 MW and include manufacturers (32%), government/education facilities (30%), commercial and retail businesses (11%), and health care (11%) and public works (16%) facilities.

II. Energy Pricing, Products and Services

SC-3A customers have a variety of choices for their electricity supply and related products and services. These options, which are summarized in Figure 1, may affect customers' incentives to respond to high hourly prices.

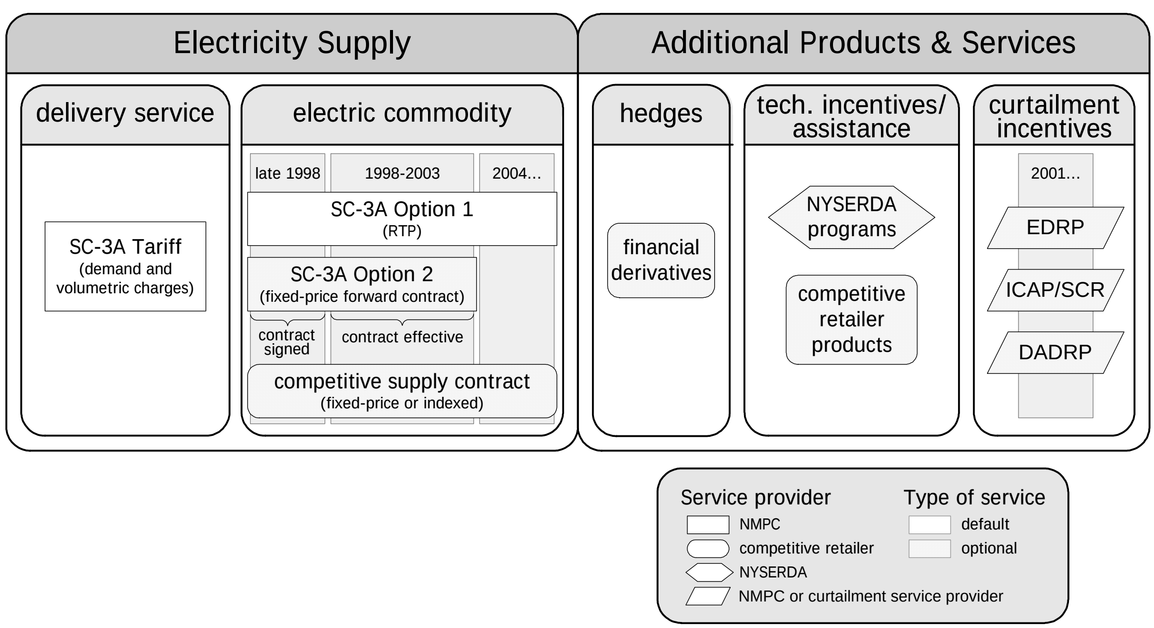

Figure 1. Choices Available to SC-3A Customers

All SC-3A customers pay common unbundled distribution rates, consisting of volumetric (per kWh) and demand (per kW) charges that collect capacity, delivery and other non-energy costs. For electric commodity, NMPC customers had several options during the study period.

A. Option 1

The default SC-3A commodity service was initially referred to as “Option 1” and it applies to all customers that do not select another commodity supply option. It consists of hourly electricity prices derived by adding ancillary services and balancing charges to NYISO’s location-based day-ahead market prices.[9] The next day’s prices are posted on the utility’s website by 4 p.m. each day. They are firm and applicable to all of the next day’s corresponding metered hourly usage.

In 2000, 60-65% of the 149 SC-3A customers purchased their electricity under the default rate. By the summer of 2004, only 36%, representing 34% of the class load, remained on the default rate. Though many customers have migrated to competitive suppliers, customer acceptance of the default service tariff design is fairly high: survey respondents gave it an average rating of 3.2 out of 5 (5 indicating complete satisfaction). . We believe this is due to several factors: increasing numbers of competitive suppliers offering alternatives, relatively low electricity price volatility in recent years, and the day-ahead notification of prices, which provides time for customers to plan and execute their response. Some survey respondents indicated that they would be more likely to leave the utility if the default service were indexed to the real-time market, which affords no advance notice of prices, as has been done in New Jersey and Maryland.

B. Option 2

NMPC offered a hedged alternative, called “Option 2”, on a one-time basis just prior to the implementation of retail competition and default-service RTP in late 1998. Option 2 was a forward contract that offered a pre-determined TOU rate schedule. Customers electing this option had to specify peak and off-peak electricity quantities to which the Option 2 pricing schedule would apply for each month of the five years covered by the contract, but they could nominate no usage in certain months or years if they wanted. The terms were somewhat restrictive; customers had to pay for all nominated load whether they used it or not. About 18% of SC-3A customers elected this option. Their average on-peak nomination turned out to cover about 60% of their actual peak-period usage. The Option 2 contracts expired in August 2003.

C. Competitive Alternatives

SC-3A customers also had the option of purchasing their commodity from competitive retailers since RTP became the default service in 1998. Their migration patterns between NMPC and competitive suppliers over the past five summers are illustrated in Figure 2. Each horizontal bar in the figure represents a single customer’s supply history. Customers are grouped according to their switching behavior patterns. In 2000, only 30% of customers had left NMPC for the competitive market. By 2004, 63% had switched. Much of this increase occurred in 2004 (the last year of the study). This coincides with the expiration of the Option 2 contracts and was also aided by the growth and maturation of the retail market in New York as well as in neighboring states that implemented retail choice and default-service RTP.

Figure 2 provides insights into large customers' switching behavior. First, about 28% of customers never left the utility at all. Of those that did, three-quarters did not return to NMPC once they had left. Only 18% moved back and forth between NMPC and the competitive market. Another group of customers (17%) had already left the utility by the summer of 2000 and never returned.

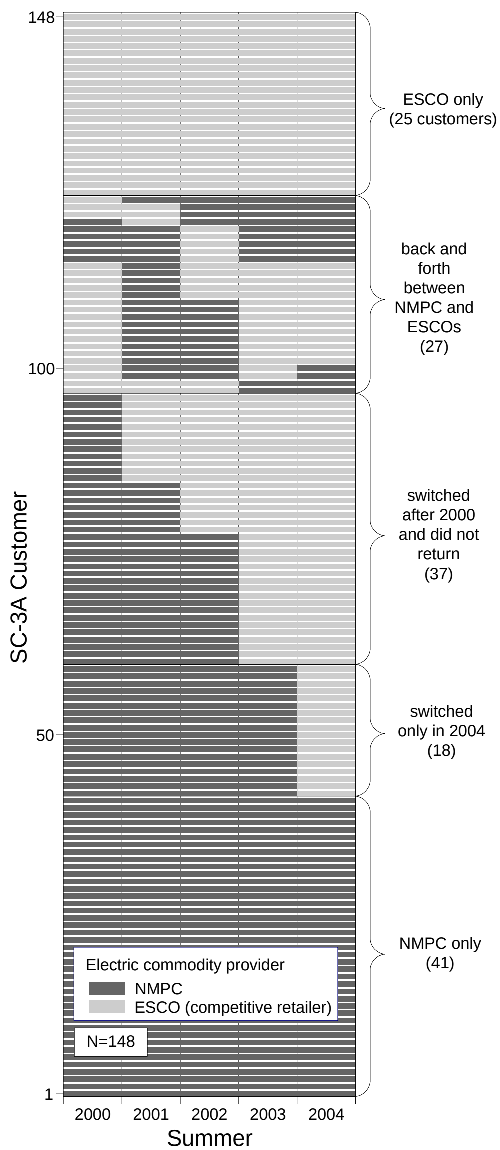

Figure 2. Migration Patterns of SC-3A Customers

Customers report that competitive suppliers offered two basic types of commodity pricing during the study period: fixed and indexed. Fixed-rate tariffs reported by customers include TOU and flat-rate pricing, typically applying to all of the customer's usage. These products reduce or eliminate the customer's incentive to respond to hourly prices. However, affected customers may still respond to other curtailment signals, such as NYISO emergency program events, if they are inclined to do so.

The majority of survey respondents that switched reported taking indexed commodity products. Most were indexed to NMPC's Option 1 tariff, but some customers reported products indexed directly to the NYISO day-ahead market or to some other reference prices. These indexed products typically provided a discount relative to the default SC-3A rate (derived from a shopping credit built into the SC-3A service), but were of the same day-ahead RTP structure.

Based on survey responses and tariff history information provided by Niagara Mohawk, we estimate that 7% to 25% of SC-3A customers took an indexed supply product in 2004. Together with customers taking the default service (Option 1), we estimate that 45-60% of SC-3A customers were facing day-ahead, hourly prices in 2004. Clearly, default-service RTP can result in large numbers of customers facing hourly prices, even among those switching to competitive suppliers.

D. Financial Hedge Products

SC-3A customers also had opportunities to purchase financial hedges through the retail market during the study period. Separate from the supply of electricity, these products provide price risk protection, typically for a pre-specified volume of electricity, with the customer still exposed to hourly prices for marginal usage.[10] Fewer than 10% of SC-3A customers appear to have purchased these price protection products. In surveys and interviews, most customers were either unclear what a financial hedge is or reported difficulties procuring them, largely due to restrictions or purchasing practices imposed by their organization. Some reported that different departments are responsible for purchasing energy and financial products, which complicates the decision. Others reported rules prohibiting them from purchasing financial derivatives altogether.

E. Enabling Technologies

One reason often offered for low price response is that customers lack the information and controls they need to effectively carry out a price response strategy. Many SC-3A customers had available, or installed during the study period, technologies with the potential to enhance their price response capability, in some cases funded by New York State Research and Development Agency (NYSERDA) programs explicitly designed to encourage DR. The impact of these technologies on customers' price response is described in section III, below.

F. NYISO Emergency DR programs

Forty-two percent of SC-3A customers enrolled in one or both of NYISO's two emergency DR programs – the Emergency Demand Response Program (EDRP) and the Installed Capacity/ Special Case Resource Program (ICAP/SCR) – for at least one summer between 2001 and 2004.[11] EDRP is a voluntary program that pays the higher of a

$500/MWh floor price or the locational real-time energy market price when NYISO calls emergency events. ICAP/SCR participants receive capacity payments and, since 2003, energy payments for load curtailed when NYISO declares emergency events. The ICAP/SCR program levies penalties for participating customers who fail to curtail when called upon to do so. We discuss the contribution of the NYISO emergency programs to SC-3A customers' price response in section V.

III. How Customers Respond

Customers' survey and interview responses provide important insights into how large customers currently adapt and respond to day-ahead market prices. We highlight the following results.

A. Load Response Strategies

We asked customers how they respond to high hourly prices, NYISO emergency events or public appeals to conserve. More than two-thirds reported some sort of response capability (see Figure 3). The most commonly reported strategy is foregoing discretionary load without making it up later – 45% of survey respondents said they respond by reducing non-essential loads. Twenty-two percent said they could shift load from one time period to another, and 16% reported serving load with onsite generation. Thirteen percent of survey respondents reported more than one load response strategy.

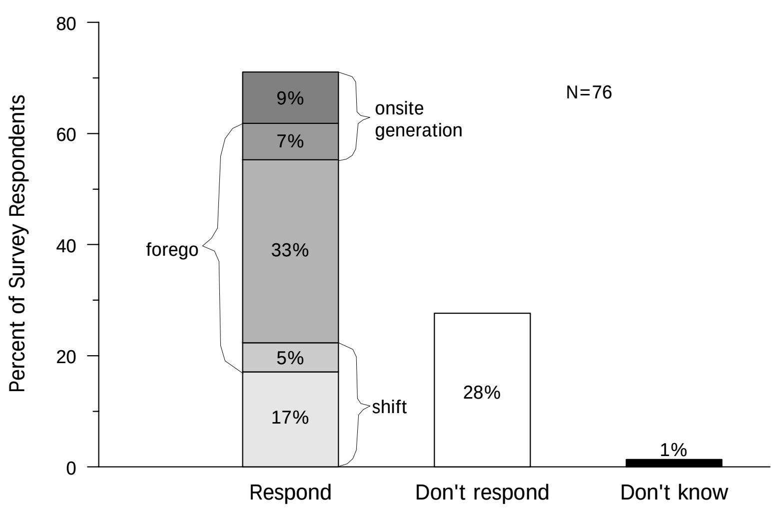

Figure 3. Self-Reported Load Response Strategies

Customers reported specific curtailment actions consistent with the prevalence of discretionary load curtailments. These actions are relatively "low-tech" – they include turning off lights, reducing air conditioning and office equipment, and asking employees to reduce usage. Some industrial customers reported shutting down plants or buildings or altering their production processes. Though pilot studies have demonstrated the potential for semi- or fully automated DR through integrated energy management and information systems, most large customers currently do not have such systems or practices in place.[12]

B. Impact of Enabling Technologies

Many SC-3A customers have installed technologies and systems that have the potential to assist with price response. Among 76 survey respondents, 49% reported ownership of energy management control systems (EMCS) and/or peak load management (PLM) devices, 41% reported owning energy information systems (EIS) and 55% reported onsite generation. However, the majority indicated that they do not use these systems to respond to high hourly prices. Instead, EMCS/PLM and EIS devices are typically used for across-the-board energy savings (efficiency-type improvements) or managing peak demand charges, and onsite generation is most often used for emergency backup or reliability reasons. We did find a correlation between the presence of onsite generation and highly responsive customers. Overall, though, we were unable to find a meaningful statistical relationship between ownership of these technologies and customers' price response, although this is probably influenced by a small sample size (we only had sufficient information to perform this analysis on 55 customers). As explanation, some customers told us the potential savings from responding to high prices do not justify investing in strategies to respond. This ties in closely with customers' reported barriers to price response, which we discuss next.

C. Barriers to Price Response

Most survey respondents (88%) reported encountering at least one barrier to price response (see Table 1). The most common obstacle, reported by half of respondents, was a lack of time or resources to monitor prices. Fully 70% said they rarely or never review the hourly prices posted by NMPC each day. For some, this precludes price response. Others appear to rely on coincident signals – NYISO emergency events or hot weather – to alert them of high prices. About a third of survey respondents reported encountering institutional barriers to price response.

Table 1. Barriers to Price Response

Barrier	**Percent of Respondents[a] (N=76)**
Organization/Business Practices	
Insufficient time or resources to pay attention to hourly prices	*51%*
Institutional barriers in my organization make responding difficult	*30%*
Inflexible labor schedule	*21%*
Inadequate Incentives	
Managing electricity use is not a priority	*22%*
The cost/inconvenience of responding outweighs the savings	*22%*
Risk Aversion/Hedging	
My organization's management views these efforts as too risky	*13%*
Flat-rate or time-of-use contract makes responding unimportant	*12%*
Other barriers	3%
No barriers encountered	12%
Do not know	3%

[a] Customers were asked to check all barriers that applied, so responses do not add up to 100%.

During our study period, SC-3A price volatility has been modest, particularly in the latter years of the study (Figure 4). While there were instances of very high prices (in excess of $500/MWh), they were isolated to a few summer days and declined in frequency and severity in the later years of the study. Accordingly, about 22% of survey respondents cited inadequate incentives as an obstacle to price response. For some, this may simply result from their not monitoring prices, as described above. But for others, this may suggest latent capability that might be expressed under conditions of greater price volatility, or that could be brought out with appropriate training and technology.

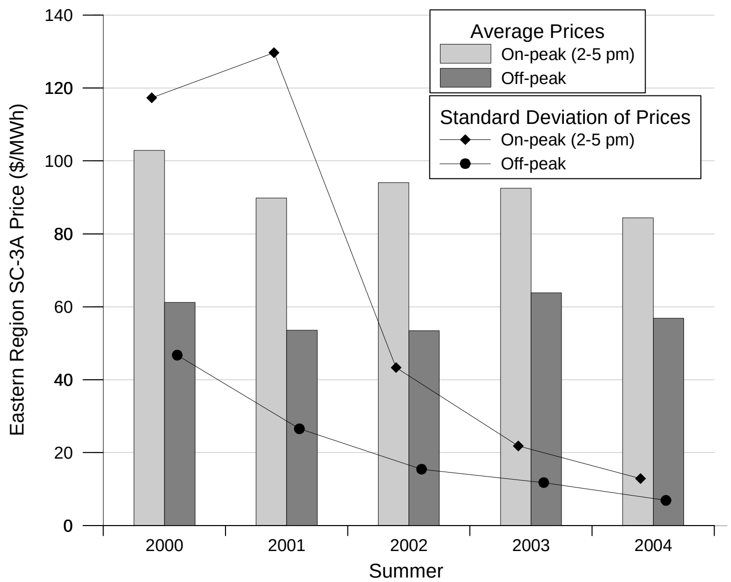

Figure 4. Trends in SC-3A Prices

Note: Prices are shown for the Eastern region of NMPC service territory. Prices and price volatility in other NMPC regions were somewhat lower.

Despite these reported obstacles, SC-3A customers' billing records suggest that a sizeable number of them adjusted their usage when prices were high. This response is discussed in the next section.

IV. Price Response Estimates

We estimated price elasticities from customers' metered electricity usage and the prices they faced during the five summers of the study (2000-2004). Customers were included in the analysis for all summers in which they paid SC-3A prices, or an indexed equivalent, for some or all of their usage. A total of 119 of the 149 customers met this criterion for at least one summer.

A. Interpreting the Elasticity of Substitution

The elasticity of substitution is used in this study to describe the price response of SC-3A customers, which are large industrial, commercial and institutional customers that use electricity as an input to producing intermediate or final goods or providing services to consumers or society. Electricity usage is portrayed in a demand model in terms of peak-period and off-peak period usage. The model measures how electricity usage can be shifted from one part of the day to another to reduce overall electricity costs. The elasticity of substitution describes the extent to which a customer shifts usage that would normally occur during the peak hours to off-peak hours in response to a change in the ratio of peak and off-peak prices.[13]

The elasticity of substitution is defined as the proportional change in peak to off-peak usage in response to a one-percent change in peak to off-peak prices. For example, a customer with an elasticity of 0.15 is expected to reduce peak-period electricity usage by 15% (relative to off-peak electricity) in response to a doubling of the ratio of peak to off-peak prices (e.g., an increase in peak prices from 5 to 10¢/kWh, with off-peak prices held constant). Substitution elasticities take on values of zero or greater: the higher the elasticity, the greater the response.

Virtually all studies of large customer response to RTP have estimated substitution elasticities, for three reasons.[14] First, because large customers are businesses (not consumers), it is theoretically consistent to portray their energy usage as a tradeoff in substitutable commodities (peak and off-peak electricity) that must be purchased in order to fulfill their business activities.[15] Second, although some propose the use of own-price elasticities, which provide direct load-reduction estimates, calculating meaningful estimates of own-price elasticity requires the analyst to account for any changes in business activity that might alter electricity usage independently of prices. For industrial customers, this might be approximated by production data (e.g., number of widgets produced). For service-oriented customers – the majority of our study population – defining a metric for business activity is even more challenging. In either case, collecting this type of information from customers is not feasible, because it is both sensitive and onerous to collect. Finally, recent in-depth analyses of the hour-by-hour pattern of price elasticities reveals that most large customers treat three to five consecutive afternoon hours as a single commodity for which the rest of the day serves as a substitute.[16] For these reasons, we report substitution elasticity estimates that indicate the extent to which customers reduce peak usage in response to higher peak prices.[17]

B. Aggregate Price Response

The overall level of price response from SC-3A customers is modest, but encouraging: the load-weighted average elasticity of substitution is 0.11. This result is consistent with other studies of large customer price response that also estimated substitution elasticities.[18]

Policymakers are particularly interested in the peak load reductions from RTP – the amount of DR they can expect at high prices. The estimated aggregate DR from the 119 customers is shown in Figure 5. At peak prices five times higher than off-peak prices (the highest price ratio observed during the study period) this group of customers would be expected to curtail their electricity usage by about 50 MW. This is about 10% of their combined summer peak demand.

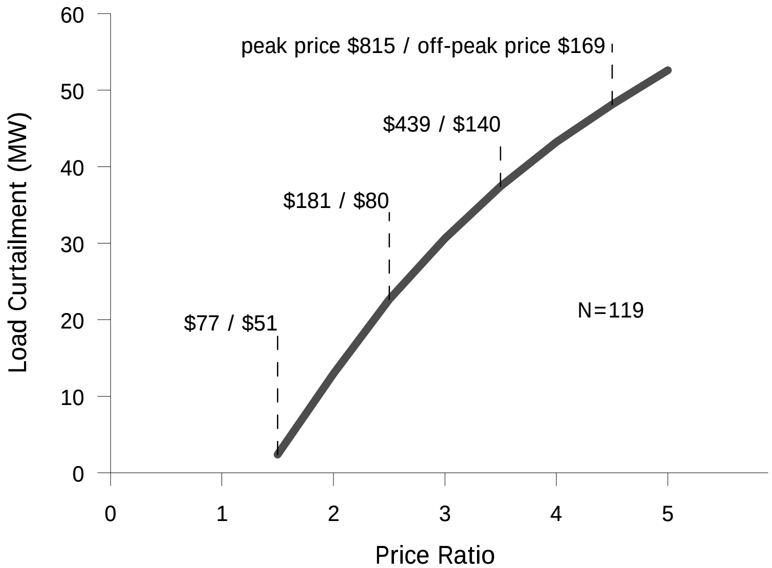

Figure 5. Aggregate Load Response of 119 SC-3A Customers

C. Response Varies by Business Sector

We also estimated load-weighted sector-average elasticities for various business sectors. The manufacturing sector exhibited the highest elasticity, of 0.16. Government/education customers are also quite price-responsive (0.10) – an important finding since most voluntary RTP programs have targeted industrial customers on the assumption that they are the best candidates for price response. The other sectors – commercial/retail, health care and public works – are considerably less responsive, with average elasticities of 0.06, 0.04 and 0.02, respectively.

D. Individual Customer Response

While the sector-level results above show clear distinctions between different customer groups, they mask considerable variation in price responsiveness among customers within each group. About one-third of customers had zero elasticity estimates. This means that they used peak and off-peak electricity in fixed proportions, regardless of prices. For the other two-thirds of customers with positive substitution elasticities, we observe some degree of price response, although there is a wide variance in that capability (see Figure 6). It is worth noting that 18% of the customers provide ~75-80% of the aggregate demand response.

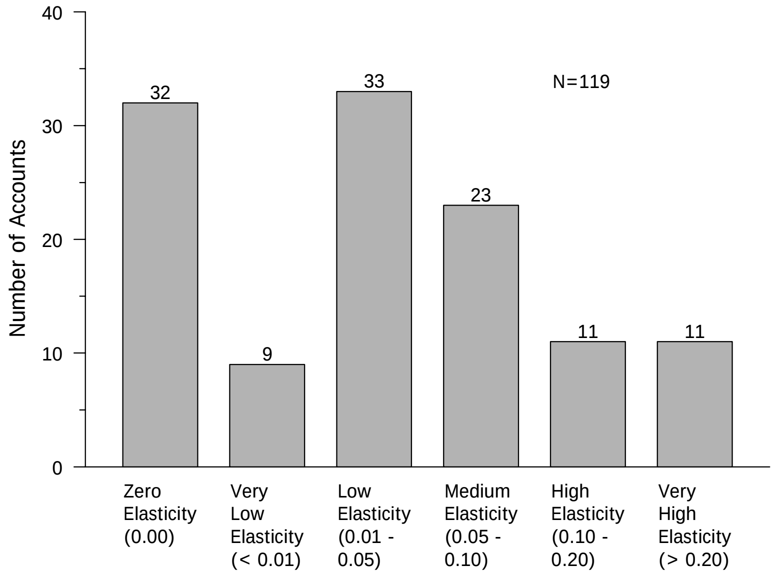

Figure 6. Distribution of Customers by Price Responsiveness

Even within business sectors, there is wide variation in price response (see Figure 7). This is most pronounced for manufacturing customers. Twenty-seven percent are highly price responsive, with elasticities above 0.10. But 63% are essentially unresponsive (elasticities < 0.05), including 27% with zero elasticities. The high average level of price response for this sector is provided by a few, very responsive customers. Within the government/education sector, price responsiveness is somewhat more evenly distributed.

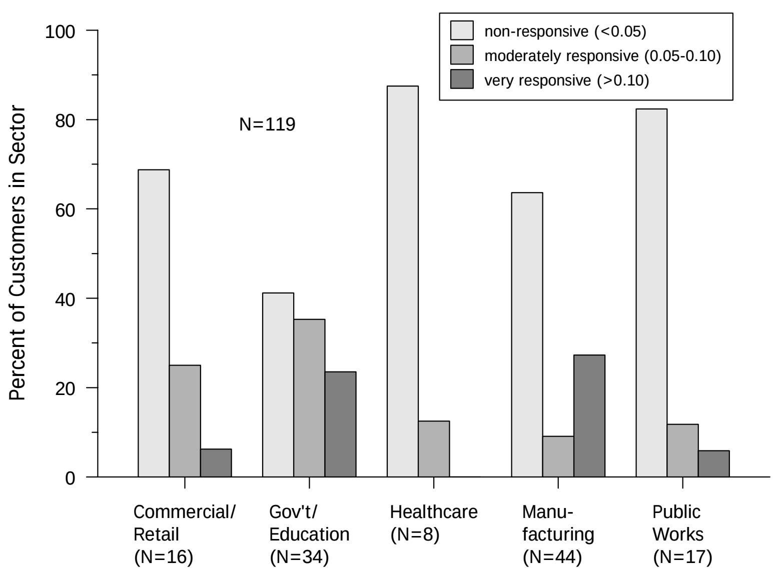

Figure 7. Price Responsiveness by Business Category

Clearly, there are other factors, besides business sector, that determine price responsiveness. As already mentioned, onsite generation appears to be a driver for the most highly responsive customers. In section V, we discuss another important factor –

NYISO emergency DR program participation. Based on our experience interviewing customers, we believe that a fourth important, though difficult to identify, driver is the presence of a price-response “champion” within customer organizations.

E. Impact of Weather and Prices

The changing conditions over the study period allowed us to study how large customers respond under various pricing and weather conditions. We found that government/education and commercial/retail sector customers responded more on hot days than cooler days. For government/education customers, this results in an increase of about 20% in the sector-average elasticity, and commercial/retail customers double their response on hot days. Even though these customers typically have increased air conditioning requirements on hot days, they clearly view these loads as discretionary when they see a large enough incentive (either a high price or a declared system emergency). For the other business sectors, little or no difference in elasticity was observed on hot and cool days.

The same sectors – government/education and commercial/retail – also increase their response on days when nominal peak prices are high, even after accounting for their increased response to hot weather (which is correlated with high prices). On average, government/education customers increase their response by about 15% when peak prices rise by 50% relative to off-peak prices – this is typically associated with elevated nominal peak prices. Commercial/retail customers increase their response by ~13% under the same conditions. This finding comports with the response strategies reported by these customers in surveys; for example, the majority of government/education customers (83%) respond with discretionary curtailments. Apparently, these customers are more willing to forego air conditioning or other discretionary loads above a threshold price. These results are encouraging – they suggest that for a significant portion of the large customer base, the most price response can be expected when it is most needed, under conditions of high prices and extreme weather.

Manufacturing customers in our sample typically did not increase their response when prices were high. This suggests that they respond primarily to changes in relative, rather than nominal, peak and off-peak prices. This too is consistent with survey responses; 40% of manufacturing customers reported shifting load to another time period, compared to very few customers in other sectors.

V. Influence of NYISO Emergency Programs

While the need for improved DR is widely acknowledged, the relative roles and merits of pricing and incentive-based mechanisms for achieving it are the subject of considerable debate.[19] As already noted, 42% of NMPC’s SC-3A customers enrolled in NYISO’s Emergency DR programs, which offer incentives to curtail load when emergency events are declared. The experience of these customers, exposed to both RTP and DR programs, provides some insights into this issue.

A. NYISO Emergency Programs Enhance Price Response

We found that NYISO EDRP participants had higher elasticities than non-participants, even though we accounted for the incentive price in the demand model.[20] This suggests that customers do not respond to EDRP events in the same way as to hourly prices, even when the financial incentives are equivalent. We discuss the reasons for this below.

B. What do Customers Respond to?

In surveys and interviews, more customers told us they respond to NYISO program events (60%) than high hourly prices (5%). They cited multiple reasons for responding to NYISO programs. While 63% reported responding to earn curtailment incentives, 59% told us they respond as part of a perceived civic duty to help keep the electric system secure. In such cases, responding is seen more as obligation to the community than an economic decision. In addition, 30% noted the coincidence of NYISO emergency events and high hourly prices as a reason for responding to NYISO program events. As discussed in section III.C, most customers say they do not actively monitor SC-3A prices. For some, NYISO emergency events, which coincide with high prices, serve to alert them that electricity prices are high.

C. Some Observations

Drawing from these results, we make the following observations. First, day-ahead RTP and emergency DR programs fulfill separate needs through distinct designs and attributes. Day-ahead RTP involves routinely sending price signals to customers on a day-ahead basisand promotes *economic* price response, in which customers are motivated by savings from curtailing usage when prices are high. This response provides system-wide benefits in the form of lower wholesale market clearing prices. In contrast, NYISO emergency programs send signals on a contingency basis (two-hour timeframe) to promote *emergency* response, thereby providing system reliability benefits.

There are also considerable synergies in implementing day-ahead RTP in conjunction with emergency programs. In interviews, we encountered customers who had developed response strategies specifically to respond to NYISO programs which they subsequently adapted to respond to high SC-3A prices. The converse was also true for other customers. Thus, RTP can provide a training ground for customers to respond in emergency DR programs, and vice versa.

We conclude that day-ahead RTP and emergency DR programs complement each other. Rather than viewing the decision to implement these two DR-enhancing mechanisms as an "either-or" proposition, policymakers should recognize their synergies. Not only do they provide different types of signals to satisfy different system needs, but the overall DR potential from exposing customers to both is potentially greater.

VI. Conclusions

The Niagara Mohawk SC-3A pricing program provides a unique source of information about how customers adapt to default service pricing 1) based on day-ahead market hourly prices, 2) in the context of retail competition and 3) in conjunction with opportunities to participate in emergency DR programs. It was implemented on a permanent basis, not as a pilot, over several years, so this study reflects a relatively mature customer understanding of price and market trends.

The results provide evidence that default-service day-ahead RTP does promote everyday economic price response among large customers, even among many who have switched suppliers but still elect to face day-ahead market prices. Analysis of SC-3A customers' billing data and hourly prices suggest that they would reduce their coincident peak demand by about 10% in response to prices of $500/MWH and higher. We also found that about 15-20% of the customers account for 80% of the observed demand reductions. Policymakers need to recognize that most large customers are currently not very price responsive, in part because they do not adopt fully automated DR strategies, even though many have installed the technologies necessary to do so. This suggests that there is a role for targeted technical assistance programs to help customers develop more sophisticated price response strategies.

Day-ahead default-service RTP for large customers serves not only as an effective means to improve the linkage between wholesale and retail markets, but it also promotes the development of retail competition. The default service sets a standard for competitive alternatives and its structure shapes the types of retail market products that develop, so implementing RTP can have a wide-reaching influence on the amount of load in the market that is exposed to and can respond to hourly prices. Moreover, this default tariff service is compatible with emergency DR programs implemented to protect system reliability. While initial price response is relatively modest, by providing technical assistance where it is most needed, policymakers can build a diverse and substantial DR resource from large customers.

Acknowledgements

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Endnotes

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[1] See Severin Borenstein, *Long-Run Efficiency of Real-Time Pricing*, ENERGY J., 26 (3), 2005, at 96, and L. Ruff, *Demand Response: Reality versus "Resource"*, ELECT. J., 15(10), at 10-23.

[2] Jay Zarnikau, *Customer responsiveness to real-time pricing of electricity*, ENERGY J., 11(4), 1990, at 99-116, J.A. Herriges, S. M. Baladi, D. W. Caves and B. F. Neenan, *The Response of Industrial Customers to Electric Rates Based Upon Dynamic Marginal Costs*, REVIEW OF ECONOMICS AND STATISTICS, 75(20), 1993, at 446-454, Steven Braithwait and Michael O'Sheasy, *RTP Customer Demand Response – Empirical*

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[3] Ahmad Faruqui and Stephen George, *Quantifying Customer Response to Dynamic Pricing*, ELECT. J., 18(4), May 2005, at 53-63, summarizing the results of a California pilot that involved TOU and CPP pricing, report that participants adjusted loads by 6–35% when faced with higher than normal prices, with the highest responses exhibited by those on CPP. Summit Blue, *Evaluation of the Energy-Smart Pricing Plan*[SM] *Project Summary and Research Issues*, report to the Community Energy Cooperative, February 2004, reports that residential customers at Commonwealth Edison paying day-ahead hourly prices reduced load by 5-10% when prices rose above typical levels.

[4] G. Barbose, C. Goldman, and B. Neenan, *Real Time Pricing Tariffs: A Survey of Utility Program Experience*, Lawrence Berkeley National Laboratory: LBNL-54238, March 2004.

[5] G. Barbose, C. Goldman, R. Bharvirkar, N. Hopper, M. Ting and B. Neenan, *Real Time Pricing as a Default or Optional Service for C&I Customers: A Comparative Analysis of Eight Case Studies,* report to the Calfornia Energy Commission, Lawrence Berkeley National Laboratory: LBNL-57661, August 2005.

[6] *Id.*

[7] We *do not* address the question of whether RTP indexed to real-time markets, with no advance notice of prices, elicits DR. This issue is currently unresolved (see Barbose *et al.*, *supra* note 5).

[8] See C. Goldman, N. Hopper, O. Sezgen, M. Moezzi, R. Bharvirkar, B. Neenan, R. Boisvert, P. Cappers, and D. Pratt, *Customer Response to Day-ahead Wholesale Market Electricity Prices: Case Study of RTP Program Experience in New York*, report to the California Energy Commission, Lawrence Berkeley National Laboratory: LBNL-54761, June 2004 and C. Goldman, N. Hopper, R. Bharvirkar, B. Neenan, R. Boisvert, P. Cappers, D. Pratt and K. Butkins, *Customer Strategies for Responding to Day-Ahead Market Hourly Electricity Pricing*, report to the California Energy Commission, Lawrence Berkeley National Laboratory: LBNL-57128, August 2005.

[9] All ancillary services are procured by NYISO, which collects the costs through uplift charges that are assessed to load serving entities based on energy usage.

[10] The specific types of financial hedge products purchased by SC-3A customers are described in Goldman *et al.*, *2005*, *supra* note 8.

[11] NYISO also offers an economic DR program – the Day-Ahead Demand Response Program (DADRP) – in which only 3% of SC-3A customers enrolled.

[12] M. A. Piette, O. Sezgen, D. Watson, N. Motegi, C. Shockman, and L. ten Hope, *Development and Evaluation of Fully Automated Demand Response in Large Facilities*, California Energy Commission: CEC-500-2005-013, January 2005.

[13] We defined the peak period empirically. Based on a preliminary analysis of customers' usage data, the period from 2pm to 5pm afforded the most distinct patterns in customer usage in response to prices.

[14] See note 2.

[15] See Goldman *et al., 2005, supra* note 8.

[16] R. Patrick, R. and F. Wolak, *Estimating Customer-Level Demand for Electricity Under Real-Time Market Conditions*, NBER Working Paper 8213, April 2001, available at http://www.nber.org/papers/w8213 and T. Taylor, P. Schwarz, and J. Cochell, *24/7 Hourly Response to Electricity Real-Time Pricing with up to Eight Summers of Experience*, J. REG. ECON., 27 (3), at 235-62..

[17] The substitution elasticity defines relative changes in peak and off peak usage resulting from a relative price change. However, as demonstrated in Goldman *et al., 2005, supra* note 8, the substitution elasticity is consistent with reducing discretionary peak usage and operating on-site generation, neither of which results in increased off-peak usage. However, the resulting elasticity inherently underestimates the extent of peak reduction by ~5-10%.

[18] See note 14.

[19] See Ruff, *supra* note 1, Borenstein, *supra* note 1, and Richard Boisvert and Bernard Neenan, *Social Welfare Implications of Demand Response Programs in Competitive Electricity Markets*, report to Lawrence Berkeley National Laboratory, LBNL-52530, August 2003.

[20] See Goldman *et al., 2005, supra* note 8 for a discussion of how NYISO program incentives were incorporated into the demand model.